Alberta

PETROLEUM MARKETING COMMISSION

403/262-8808

1900, 250 - 6th Avenue S.W.
Calgary, Alberta
Canada T2P 3H7

August 31, 1982

The Honourable E. P. Lougheed, Premier
and
The Honourable C. M. Leitch, Minister
Government of the Province of Alberta
Legislative Building
Edmonton, Alberta
T5K 2B7

Dear Sirs:

In accordance with the provisions of the Petroleum Marketing Act, the Natural Gas Pricing Agreement Act, and the Natural Gas Price Administration Act, the Commission has prepared a general report summarizing its transactions and affairs during the fiscal year ended December 31, 1981. I have the pleasure to submit the Annual Report 1981 that you may lay a copy before the Legislative Assembly.

Respectfully submitted,

D. W. Minion
Chairman

ANNUAL REPORT
of the
ALBERTA PETROLEUM MARKETING COMMISSION

pursuant to the
PETROLEUM MARKETING ACT
and
NATURAL GAS PRICING AGREEMENT ACT
and
NATURAL GAS PRICE ADMINISTRATION ACT

for the fiscal year ended
December 31, 1981

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FOREWORD

In many respects 1981 was a turning point for the world oil industry, with reduced energy demand and a global oil surplus which was brought on in part by the worldwide economic slowdown and in part by energy conservation efforts spurred on by high consumer prices for petroleum products. The movement towards energy conservation and the substitution of alternatives for oil appeared to be remarkably effective.

The decline in free world petroleum demand, in comparison with the all-time high demand in 1979, was dramatic. The magnitude of swings in both availability and price of oil caught forecasters by surprise, accentuating the poor forecasting record of energy experts during the last ten years. Only the brave believe that free world energy demand will grow at more than three percent per year through the end of the century, a forecast commonly made only a few years ago.

Nevertheless, oil demand should rise again as the free world economy improves, but it will be a slow process and its pace may well prove inadequate to allow OPEC to retain the extent of control in oil pricing exercised in the past.

Oil reserves of the free world increased more than 20 billion barrels, with Mexico contributing more than half of the increase. This raised the reserves to production ratio to 32 years, the highest since 1971.

In Europe and North America reaction to the new circumstances resulted in the closure of a significant portion of refining capacity.

Canada belatedly followed the trend of reducing energy demand. Consumer prices for oil products increased rapidly with the result of inducing conservation. However, the price increases were due mainly to taxation while the price paid to producers for crude oil actually slipped in terms of its percentage of international price. The oil industry's response to the political and economic climate in Canada was a severe reduction in exploration and development activities.

PETROLEUM

FUNCTIONS AND RESPONSIBILITIES

The Petroleum Marketing Act created the Commission as agent to sell the Crown's royalty share and lessee's share of petroleum from Crown leases. The Commission administers the Act using procedures that embody the following:

- issuance of the Price Bulletins in which the Commission prescribes selling prices for petroleum;
- designation of operators to make deliveries of petroleum from Crown leases to the Commission;
- movement of petroleum to point of sale to buyers;
- sale by the Commission to buyers;
- remittance of proceeds of sale of the lessee's share to designated operators for distribution to owners;
- remittance of the proceeds of the Crown's royalty share to the Provincial Treasurer.

PETROLEUM SALES

During the year the Commission sold 43.9 million cubic metres of Crown royalty and lessee petroleum for total revenues of $5.20 billion. This comprised 77 percent of conventional crude oil production in Alberta. The royalty production of 17.3 million cubic metres was sold on behalf of the Crown for $2.06 billion.

Light and medium crude oil was produced at capacity during January, February and December. Production was limited from March to September by the cut-back imposed by the Government of Alberta in protest against energy policies put in place by the federal government in the absence of a petroleum pricing agreement with Alberta. Market demand was less than productive capacity during September, October and November when prorationing of production was required. Over the year, light and medium crude oil was produced at 92.1 percent of productive capacity.

Production of heavy crude oil increased from 1980 by four percent and market demand exceeded production for all months except April.

Monthly sales volumes are shown in Figure 1 with the value of those sales shown in Figure 2.

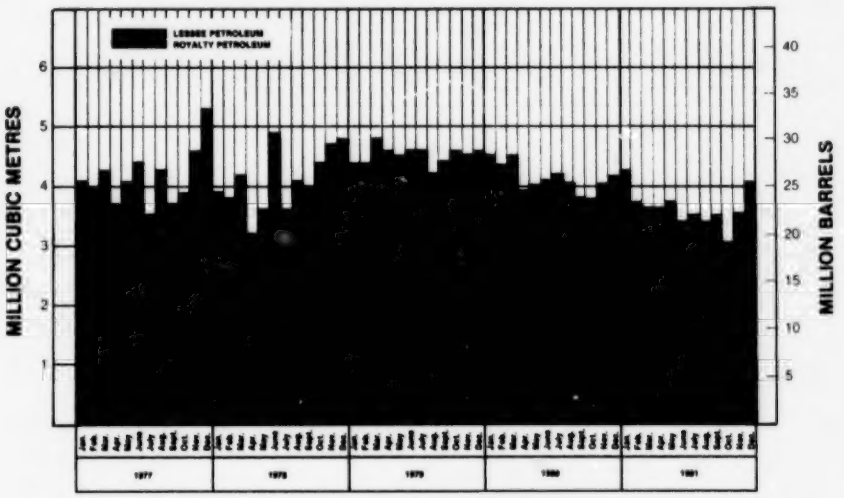


FIG. 1
MONTHLY VOLUMES — PETROLEUM SALES

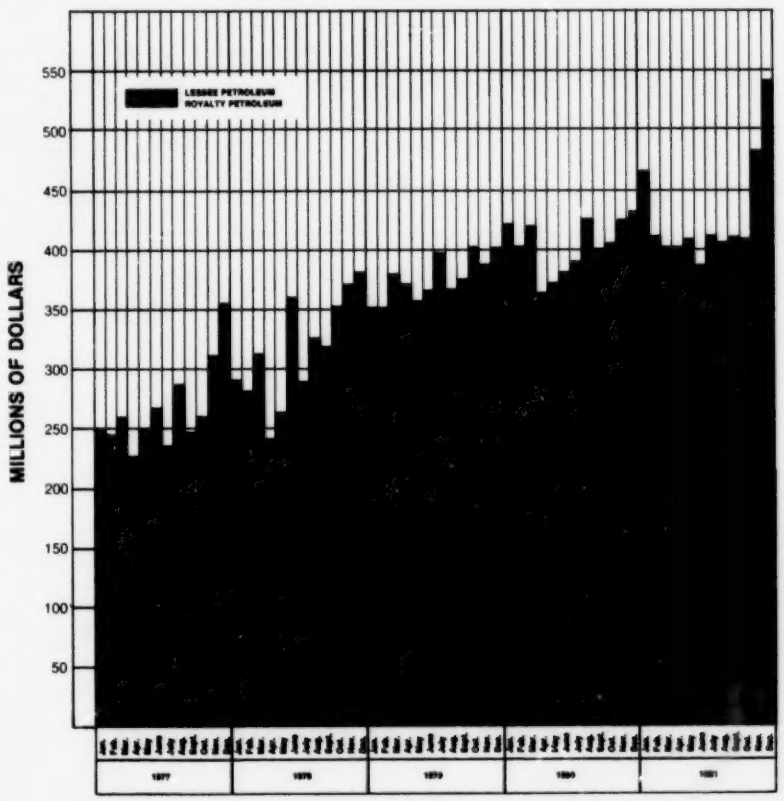


FIG. 2
MONTHLY VALUE — PETROLEUM SALES

PETROLEUM PRICING

The Commission increased average field prices of petroleum from Crown leases by $6.29 per cubic metre to $117.99 on July 1, 1981. A further increase of $15.73 per cubic metre was made on October 1, 1981 pursuant to the Memorandum of Agreement of September 1, 1981 between the Government of Canada and the Government of Alberta on energy pricing and taxation.

The Commission's Price Bulletins prescribe the prices for petroleum produced from Crown leases with the object of maintaining a specific average field price incorporating variations in quality based on density and sulphur content. During the year the Commission made modifications to the methods of pricing crude oil. Field prices were established using broader quality ranges of density and sulphur and, for a first time, heavy crude prices were determined in the same manner as light and medium crude prices. A further modification was that pipeline transportation costs from the field to interprovincial pipeline systems and other points of sale became an add-on to the posted field prices with the result that the producer receives the same price for crude oil within a given quality range regardless of the producing location within Alberta.

Table 1 shows the average field prices for Alberta conventional crude oil since April 1, 1974.

TABLE 1

Effective Date	Price Per Barrel	Price Per Cubic Metre
Apr. 1, 1974	$ 6.50	
July 1, 1976	9.05	
Jan. 1, 1977	9.75	
July 1, 1977	10.75	
Jan. 1, 1978	11.75	
July 1, 1978	12.75	
July 1, 1979	13.75	$ 86.53
Jan. 1, 1980	14.75	92.83
Aug. 1, 1980	16.75	105.40
Jan. 1, 1981	17.75	111.70
July 1, 1981	18.75	117.99
Oct. 1, 1981	21.25	133.72
Jan. 1, 1982	23.50	147.88

FUNCTIONS AND RESPONSIBILITIES

In the absence of a federal/Alberta agreement on gas pricing between October 31, 1980 and October 31, 1981 the Commission's functions and responsibilities with respect to natural gas were performed under the Natural Gas Price Administration Act. Under this Act the Minister of Energy and Natural Resources delegated to the Commission the responsibility for issuing pricing orders governing the prices to be paid to the producers for natural gas. On November 1, 1981 when a federal/Alberta agreement on natural gas pricing came into effect gas pricing reverted to the Natural Gas Pricing Agreement Act which implements the agreement. The term of the agreement extends to January 31, 1987.

The Commission's functions and responsibilities under the Natural Gas Pricing Agreement Act are as follows:

- determination of Alberta costs of service;
- purchase of gas and its subsequent sale;
- administration of a fund comprised of revenues derived from gas exports to the United States;
- determination of a price adjustment to be paid each month to producers;
- reimbursement or payment of price adjustment out of revenues in the fund;
- determination and payment of market development incentive payments to the federal government out of revenues in the fund.

NATURAL GAS SALES

During the year the Commission purchased 2 400 petajoules of gas for which it paid $3.478 billion and sold for $5.653 billion, resulting in proceeds to the fund of $2.175 billion. Total production of Alberta gas for market was 2 405 petajoules on which a price adjustment averaging $0.90 per gigajoule for the year was paid out of fund proceeds.

Figure 3 shows the quantities and destinations of gas sold by the Commission.

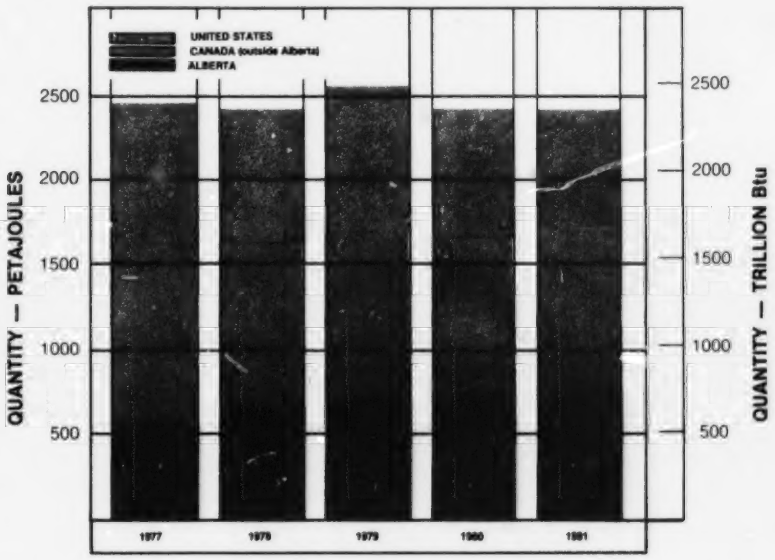


FIG. 3
DESTINATION OF NATURAL GAS SOLD BY THE COMMISSION

NATURAL GAS PRICING

The federal/Alberta gas pricing agreement of November 1, 1981 established an Alberta border price of $1.701 62 per gigajoule and provided for subsequent increases of approximately 23.3¢ per gigajoule every six months during the term of the agreement.

Under the Natural Gas Pricing Agreement Act the monthly price (regulated field price) for gas purchased by original buyers that remove gas from Alberta is:

Alberta border price
LESS
Alberta cost of service
PLUS
Price Adjustment

Gas purchased for consumption within Alberta is required to be priced as described above or the price specified in a gas sales contract plus price adjustment, whichever is the lesser.

The Commission publishes the Alberta border price and determines monthly Alberta costs of service and the amount of the price adjustment.

Figure 4 shows by month the average regulated field price and Table 2 shows a history of the Alberta border price.

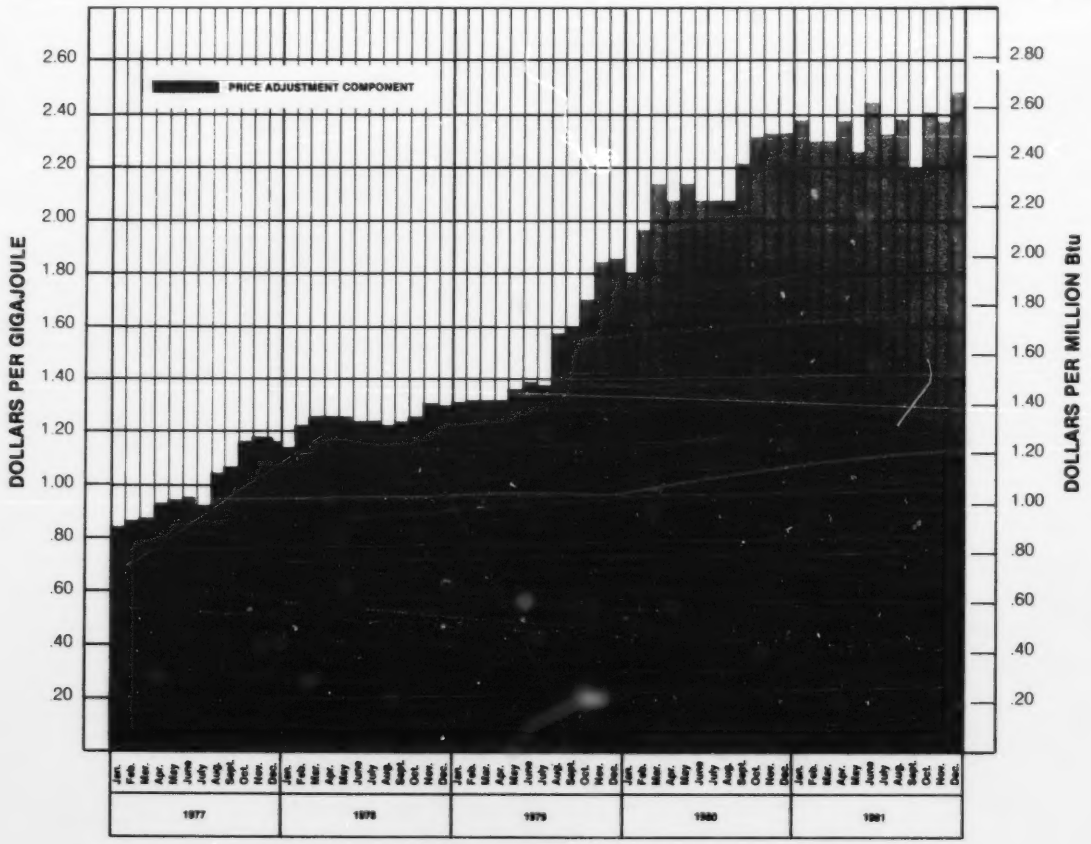


FIG. 4
REGULATED FIELD PRICE — NATURAL GAS

TABLE 2

Effective Date	Toronto City Gate Price	Cost of Transportation Alberta to Toronto	Imputed price at Alberta border	
	($/MMBtu)[1]	($/MMBtu)[1]	($/MMBtu)[1]	($/MMBtu)[2]
Nov. 1, 1975	1.250	.42339	.82661	.81223
Dec. 1, 1975	1.250	.41851	.83149	.81703
July 1, 1976	1.405	.43304	.97196	.95506
Jan. 1, 1977	1.505	.45272	1.05228	1.03398
Aug. 1, 1977	1.680	.46681	1.21319	1.19209
Feb. 1, 1978	1.850	.48336	1.36664	1.34287
Aug. 1, 1978	2.000	.59023	1.40977	1.38525
	($/GJ)	($/GJ)	($/GJ)	
Jan. 1, 1979[3]	1.864 06	.550 11	1.313 95	
Aug. 1, 1979	2.003 86	.590 11	1.412 97	
Feb. 1, 1980	2.143 67	.602 61	1.541 06	
Sept. 1, 1980	2.423 28	.629 20	1.794 08	
Nov. 1, 1980	2.423 28	.647 63	1.775 65[4]	
Sept. 1, 1981	2.423 28	.721 66	1.701 62[4,5]	

[1] Saturated basis (federal standard)
[2] Dry basis (Alberta standard)
[3] This does not represent a change in prices but reflects the introduction of SI commencing January 1, 1979.
[4] Established by the Government of Canada pursuant to the Petroleum Administration Act.
[5] Alberta border price confirmed by federal/Alberta agreement.

ALBERTA COST OF SERVICE

Original buyers that remove gas from Alberta apply to the Commission each month for determination of Alberta costs of service in respect of gas purchased in the month. The Commission makes determinations for nine original buyers, some of which apply for two or more costs of service, depending on the points of gas removal from Alberta, areas of gas supply, and allocation of costs. Alberta costs of service consist primarily of the costs and charges relating to the acquisition of gas and its movement from the point of purchase to the Alberta border, excluding the purchase price.

In the case of gas purchased by an original buyer that does not remove gas from Alberta the Commission estimates an amount that would be the Alberta cost of service if the gas was removed from Alberta. This estimated amount is then used to determine the maximum price which the original buyer may pay for such gas.

The Commission, upon an application by an original buyer or on its own initiative, makes rulings on matters of principle and matters involving categories of costs and charges eligible for inclusion in Alberta cost of service. Any determination made by the Commission may be appealed to the Public Utilities Board for public hearing.

The monthly averages of the Alberta costs of service determined by the Commission for original buyers that remove gas from Alberta from 1977 through 1981 are shown in Figure 5.

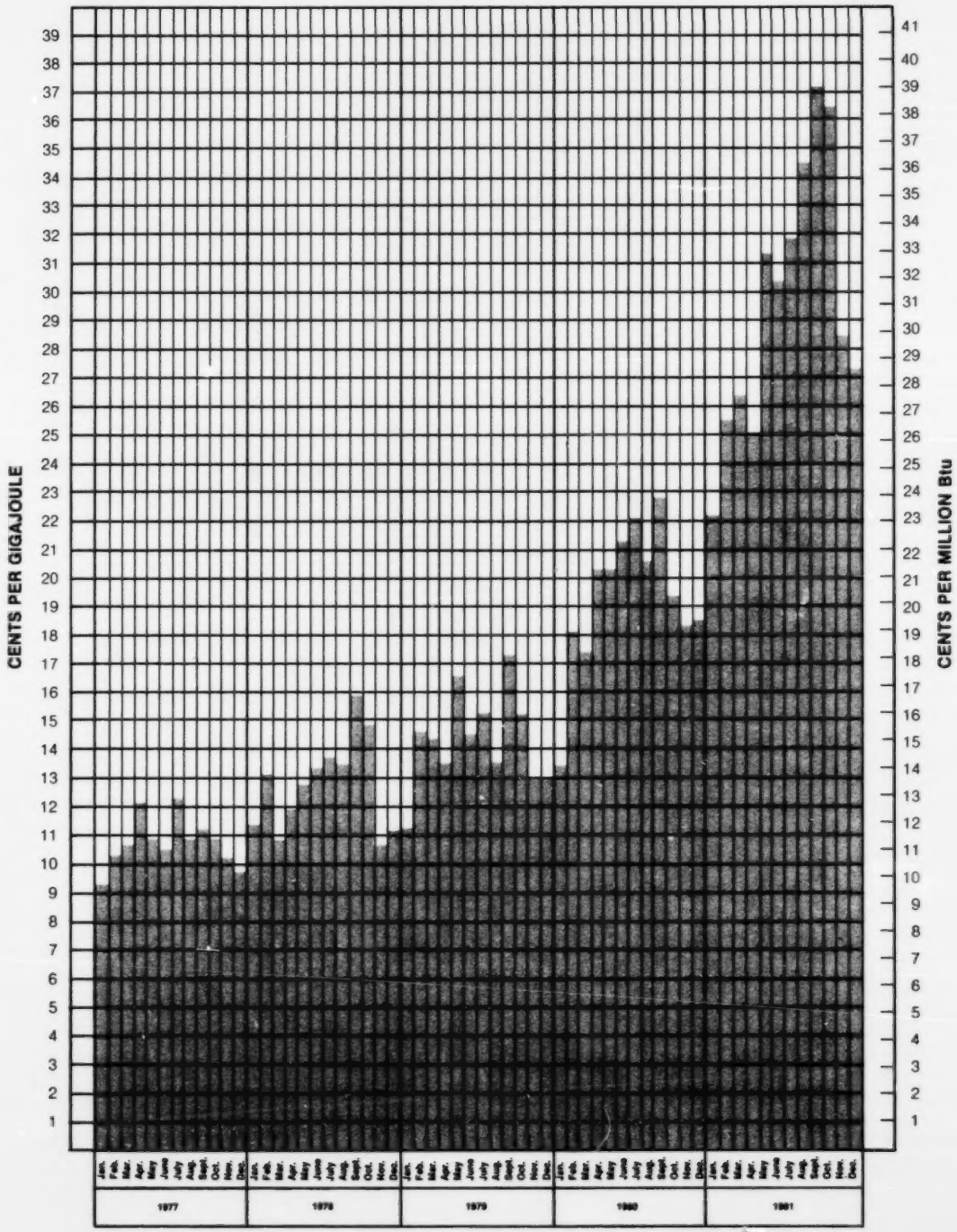


FIG. 5
AVERAGE OF ALBERTA COSTS OF SERVICE

FUND TRANSACTIONS

Substantially all gas acquired by original buyers is purchased by the Commission. Gas destined for the Canadian market is sold back to the original buyer at the purchase price. Gas destined for export to the United States is sold back to the original buyer at the export price less transmission costs. As a result of the buy/sell transactions for export gas, proceeds are obtained for the fund out of which price adjustments and market development incentive payments are made.

Prices for natural gas exported to the United States since November 1975 are shown in Table 3.

Each month the Commission calculates a price adjustment based on proceeds available in the fund and estimated quantities of gas produced in Alberta for market. Producers receive the monthly price adjustment either through the regulated field price paid by an original buyer or, in some circumstances, by claiming directly from the fund. An original buyer that pays the price adjustment is entitled to claim reimbursement from the fund.

The price adjustments expressed in dollars per gigajoule set by the Commission during the year were as follows:

January	0.83	May	0.80	September	0.87
February	0.77	June	0.97	October	1.07
March	0.79	July	0.89	November	0.96
April	0.86	August	0.96	December	1.05

In order to encourage expansion of markets for Alberta-produced natural gas in provinces east of Alberta, the federal/Alberta agreement provides for market development incentive payments to be made every three months by the Commission to the federal government. These payments received by the federal government are to be used to subsidize the expansion of natural gas transmission or distribution facilities and for sales promotion programs. A payment of approximately $5.7 million was made for the three months ended January 31, 1982.

TABLE 3

Effective Date	Export Price[1]	Average Selling Price[2]
	($/MMBtu)	($/MMBtu)
Nov. 1, 1975	1.60000	1.60000
Sept. 10, 1976	1.80000	1.80000
Jan. 1, 1977	1.94000	1.94000
Sept. 21, 1977[3]	2.16000 (U.S. $)	2.39252
	(U.S. $/GJ)	($/GJ)
Jan. 1, 1979	2.013 18	2.363 82
May 1, 1979	2.143 67	2.506 08
Aug. 11, 1979	2.610 00	3.060 59
Nov. 3, 1979	3.220 00	3.776 95
Feb. 17, 1980	4.170 00	4.845 46
April 1, 1981	4.600 00	5.509 59

[1] Except for a lower price for minor quantities exported at Fort Frances, Ontario, since January 1, 1977.
[2] Average price in Canadian dollars received for gas exports during the period in which the export price applied.
[3] Effective this date the National Energy Board prescribed the export price in U.S.$.

OTHER ACTIVITIES

SPECIAL STUDIES

The Commission carried out a program of sampling and analysis of the major crude oil, synthetic oil and pentanes plus pipeline streams in Alberta. These analyses provide information related to the product yield that can be obtained from each stream and thereby assist in marketing.

A detailed supply and demand analysis of pentanes plus was made in preparation for the Commission undertaking the marketing of pentanes plus. Pipeline systems were examined to determine changes which could be made to maximize the availability of pentanes plus supply.

A study was carried out to determine the diluent requirements for heavy crude oil movements.

The Commission carried out studies and provided information to the Alberta government for negotiation of the energy agreement with the federal government.

A study was initiated to determine the supply and demand for Alberta heavy crudes and to identify potential marketing problems.

An assessment was made of the Canadian heavy fuel oil market for purposes of determining its competitive position relative to natural gas.

REGULATORY ANALYSIS

The Commission monitors the markets for Alberta petroleum and natural gas. This involves, in part, assessing the impact of proposed energy projects in Canada that become the subject of applications for approval by the National Energy Board. During the year, the Commission intervened in several applications to the National Energy Board on natural gas projects. Evidence was presented in the hearing held by the National Energy Board for extension of a natural gas pipeline to the Maritime provinces and a hearing on rates and tolls to be charged by TransCanada PipeLines Limited and the necessity for developmental prices for natural gas.

SYNCRUDE PROJECT

Petroleum derived from oil sands leases is not required by statute to be priced or marketed by the Commission. However, the Commission performs certain functions related to the Syncrude Canada Limited project. The Commission markets the Province of Alberta's share of synthetic oil and, by agreement, the share of one other participant. The Province of Alberta has an eight percent equity participation in the project and a 50 percent share of net profits in lieu of royalty. In 1981 the net profits share was taken as production in kind with the result that during the year the Commission marketed approximately 25 percent of the total 4 731 658.4 cubic metres of synthetic oil produced by the project. In addition to the Commission's functions, the Chairman of the Commission is the Alberta Royalty Negotiator with respect to synthetic oil produced by the project. This involves establishment of the value of synthetic oil to be used as a factor in determining net profits. At year end this value was $258.23 per cubic metre at the plant gate including compensation of $126.97 per cubic metre paid by the federal government to reflect international prices.

WORLD ENERGY SCENE

INTERNATIONAL

Although 1981 was a year of relative energy price stability and some economic growth in the industrialized countries, total energy consumption in the non-communist world continued to decline, falling 1.1 percent from 1980. Most of the drop stemmed from oil conservation measures, which, in addition to inter-fuel switching, reduced oil's share in the shrinking primary energy market from 50.0 percent in 1980, to 48.2 percent in 1981. Table 4 illustrates the changes which have occurred in the pattern of primary energy consumption in the non-communist world since 1977.

Oil consuming countries of the industrialized world made some progress in finding solutions to the economic and political problems associated with reliance on imported oil with the result that oil consumption in the non-communist world dropped 6.3 percent to 46.2 million barrels per day. The largest rate of decline, 8.7 percent, occurred in western Europe where significantly higher oil costs were attributable to depreciation of local currencies. Oil consumption fell 7.5 percent in Japan and 6.2 percent in the United States. Figure 6 shows demand and supply since 1977.

The decline in oil sales brought on by falling world oil demand and inventory liquidation was borne entirely by OPEC where production dropped 15.7 percent to 22.7 million barrels per day. This reduction was not sufficient to prevent a world oil surplus from developing because Saudi Arabia, in its successful bid to unify prices, maintained production at an average annual rate of 9.6 million barrels per day.

Non-OPEC production was not affected by falling world oil demand and rose 2.4 percent to 21.0 million barrels per day. Mexican production increased 18.6 percent, bringing its average to 2.6 million barrels per day. North Sea production averaged 2.3 million barrels per day, 7.7 percent higher than in 1980.

Figure 7 plots the spot and official price of Saudi Arabian marker crude since 1977. For the first time in many years, spot prices in October fell below official prices, to exert downward pressure on the latter.

World natural gas production increased 2.3 percent to 54.0 trillion cubic feet. Although prospects for increased world trade in natural gas were not improved by the leveling of world oil prices, there were some positive developments. Algeria and France agreed in principle on a pricing formula for liquified natural gas. Japan signed long-term contracts with the USSR and Australia for liquified natural gas, in an amount equivalent to 396 billion cubic feet of natural gas per year. Italy contracted with the USSR for 292 billion cubic feet per year of natural gas to be delivered via the new Yamal pipeline, now under construction.

TABLE 4

WORLD CONSUMPTION OF PRIMARY ENERGY*

(Percentage Shares of Sources)

	1977	1978	1979	1980	1981
Petroleum	53.5	53.3	52.5	50.0	48.2
Natural Gas	18.4	17.8	17.7	18.4	19.1
Coal	18.3	18.7	19.6	21.1	21.6
Hydro Electricity	7.1	7.2	7.2	7.4	7.5
Nuclear Electricity	2.6	2.8	2.9	3.1	3.6

* Excludes Communist Countries.

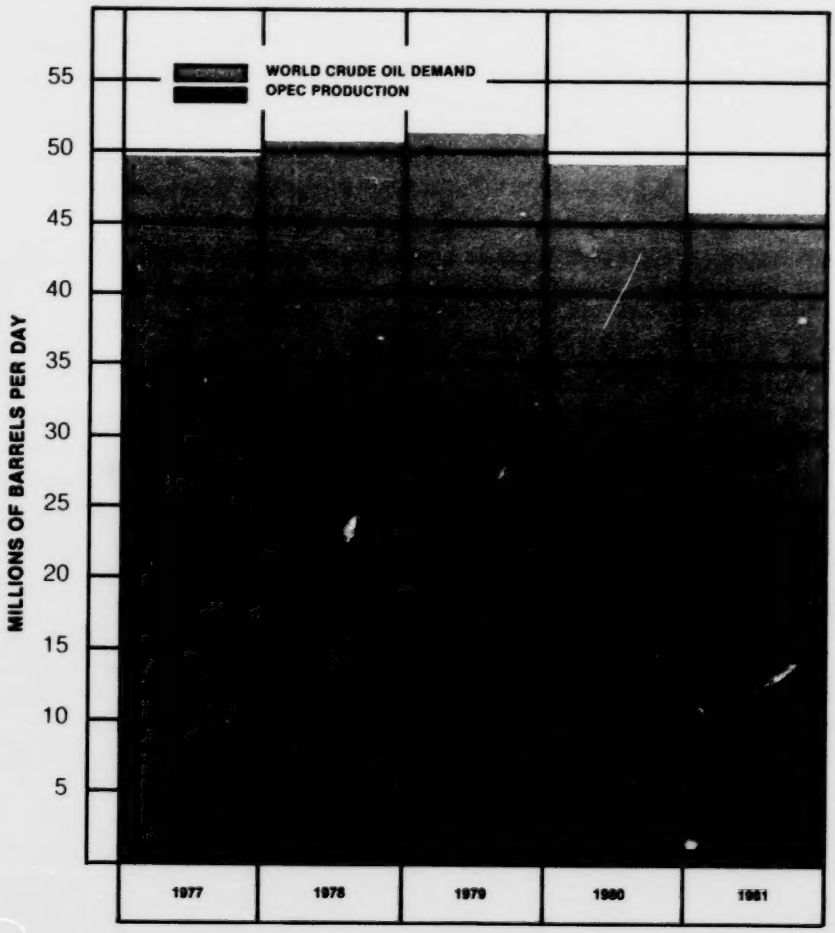


FIG. 6
WORLD CRUDE OIL SUPPLY/DEMAND
(Millions barrels per day)
***Excludes Communist Countries**

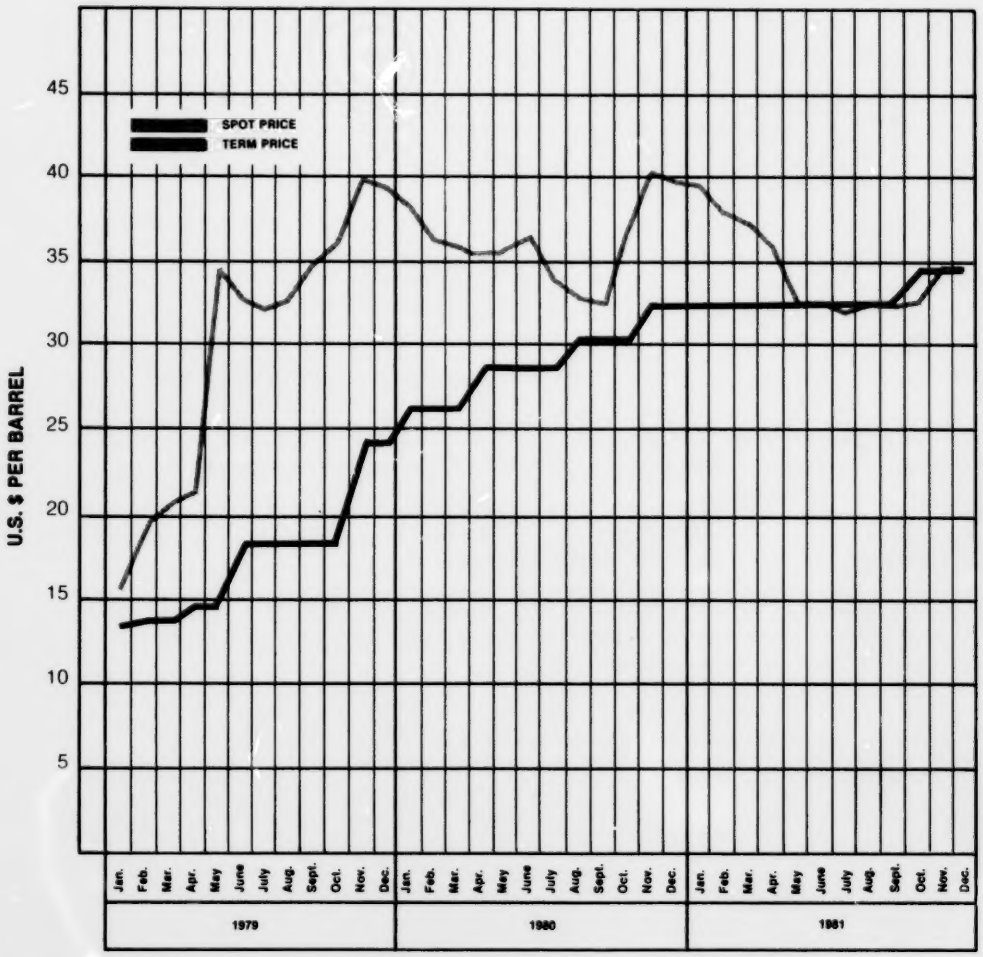


FIG. 7
COMPARISON OF SPOT AND TERM PRICES
FOR SAUDI ARABIAN MARKET CRUDE

UNITED STATES

Total energy requirements declined 2.3 percent, due to lower consumption of oil and gas. Coal increased its share of the primary energy market from 20.4 percent in 1980 to 21.6 percent in 1981. The combined share of hydroelectricity, nuclear and geothermal power increased from 7.7 percent to 8.1 percent.

The year marked an important turning point in United States energy policy. The removal of domestic crude oil price controls allowed free market forces to prevail for the first time since oil import quotas were imposed in 1959. In spite of price decontrol, domestic oil prices remained below world levels throughout the year. Table 5 shows average United States refinery acquisition costs for domestic and imported crude oil since 1977.

Petroleum consumption, which dropped 6.2 percent to 16.0 million barrels per day, reached its lowest level since 1973. Imports of crude oil and petroleum products declined 13.0 percent to 6.0 million barrels per day and domestic production of 10.2 million barrels per day accounted for 62 percent of total supply. Figure 8 shows United States petroleum consumption and supply since 1977.

For domestic oil producers, crude oil price decontrol was welcomed and generated increased exploration and development. A record 37 671 oil wells were completed, an increase of 28.3 percent from 1980. Crude oil production in the lower 48 states remained constant at 7.0 million barrels per day, reversing an eight year production decline. Alaskan production also held steady, as did the production of natural gas liquids, each of which contributed 1.6 million barrels per day to total domestic supply.

Natural gas consumption fell 1.5 percent to 19.9 trillion cubic feet, primarily because of losses in the residential heating market. Domestic production declined by only 0.9 percent while natural gas imports dropped 11.9 percent to 868 billion cubic feet. The imports were comprised of 762 billion cubic feet from Canada, 105 billion cubic feet from Mexico, and 37 billion cubic feet from Algeria in the form of liquified natural gas.

Since the introduction of the Natural Gas Policy Act of 1978, natural gas wellhead prices have risen approximately $1.00 per thousand cubic feet, averaging $1.96 at year end. Reserve additions in the lower 48 states were estimated at 21.4 trillion cubic feet, the largest total increase since Alaskan reserves were added in 1970.

Electricity consumption increased by slightly less than one percent. The decrease in use of petroleum and natural gas for electricity generation continued as fossil fuel prices favoured coal. Table 6 traces the cost of fossil fuels delivered to steam-electric utility plants since 1977.

TABLE 5

AVERAGE REFINER ACQUISITION COST OF CRUDE OIL IN THE UNITED STATES

(U.S. $ per barrel)

Period	Domestic Average	Imported Average	Composite Average
1977	9.55	14.53	11.96
1978	10.61	14.57	12.46
1979	14.27	21.67	17.72
1980	24.23	33.89	28.07
1981 Jan.	32.71	38.85	34.86
Feb.	36.27	39.00	37.28
Mar.	36.97	38.31	37.48
Apr.	35.58	38.41	36.58
May	35.21	37.84	36.11
June	34.20	37.03	35.03
July	33.76	36.58	34.70
Aug.	33.79	35.82	34.46
Sept.	33.47	35.44	34.11
Oct.	33.48	35.43	34.07
Nov.	33.49	36.26	34.34
Dec.	33.51	35.95	34.33
1981 Average	34.88	37.14	35.64

TABLE 6

COST OF FOSSIL FUELS DELIVERED TO STEAM-ELECTRIC UTILITY PLANTS IN THE UNITED STATES

(cents per million BTU)

Year	Coal	Residual Oil	Natural Gas
1977	94.7	220.4	130.0
1978	111.6	212.3	143.8
1979	122.4	299.7	175.4
1980	135.2	427.9	212.9
1981	153.3	529.0	282.8

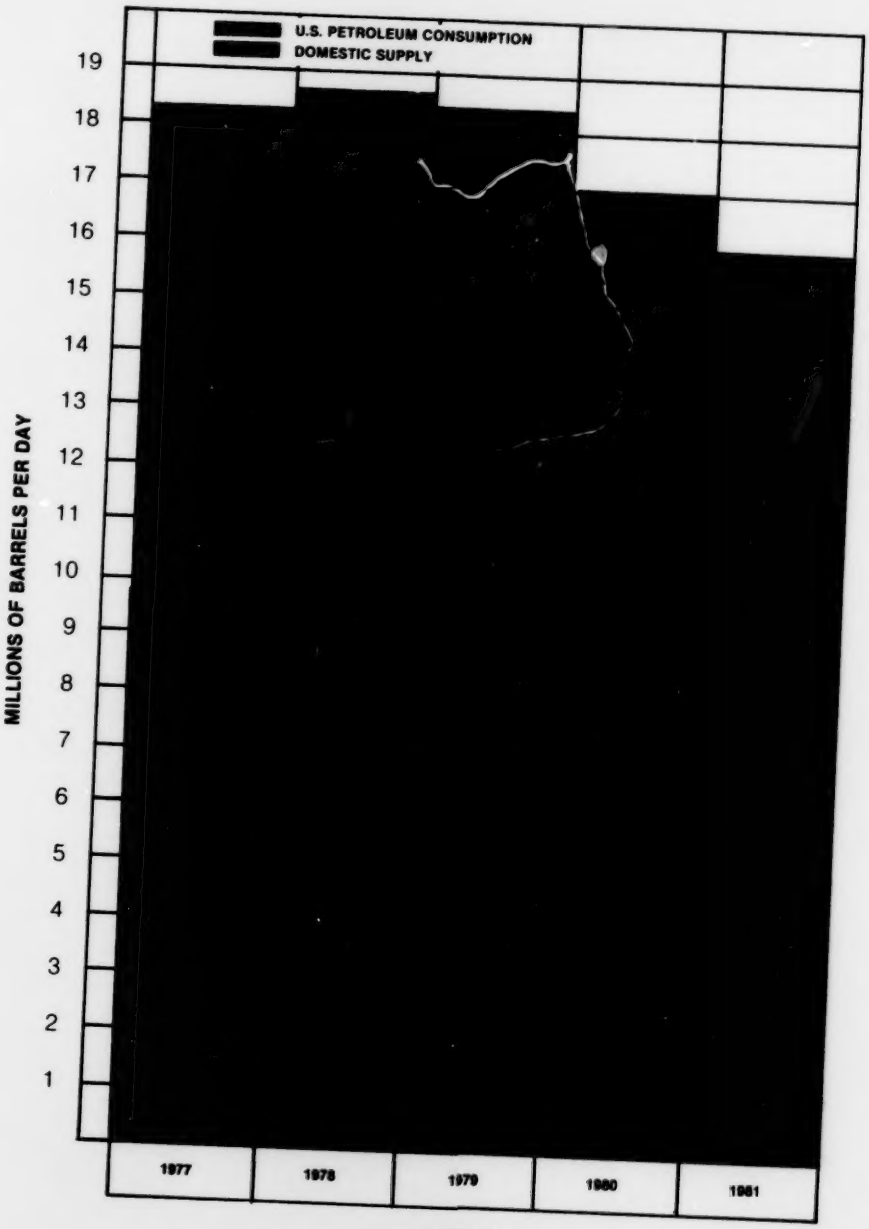


FIG. 8
U.S. PETROLEUM CONSUMPTION AND SUPPLY

CANADA

The September 1 Memorandum of Agreement on energy pricing and taxation was the highlight of a year in which Canada's energy future had been the focus of a national debate. The agreement features vintage pricing for oil and moves the reference point for natural gas field pricing from Toronto to the Alberta border. Synthetic oil and oil discovered after December 31, 1980 receive the international price. Field prices for conventional old oil and Alberta border prices for natural gas are shown in Tables 7 and 8.

Rapidly rising energy costs and economic malaise forced consumers to become more conscious of energy consumption. As a result, total energy demand, which had been increasing steadily throughout the seventies, dropped 2.3 percent to 9 262.5 petajoules. While oil's displacement was accelerated, the natural gas share of the shrinking primary energy market remained constant at 18 percent. Other energy sources, including coal, primary electricity, and biomass, increased their combined market share from 40 percent to 44 percent. Table 9 shows Canadian consumption of primary energy by source for 1980 and 1981.

Consumption of petroleum products decreased 6.2 percent to 273.2 thousand cubic metres per day. In spite of this decline, Canada's net petroleum deficit continued to increase as domestic production accounted for only 81 percent of total petroleum consumption, down from 84 percent in 1980 and 94 percent in 1975.

Production of crude oil and equivalent hydrocarbons fell 9.6 percent to 220.1 thousand cubic metres per day. Most of this decline occurred in Alberta where production of conventional crude oil and equivalent dropped 8.3 percent to 173.9 thousand cubic metres per day. Synthetic oil production averaged 17.7 thousand cubic metres per day, a decline of 11.5 percent from 1980.

Although refinery crude oil acquisition costs rose 54 percent in 1981, most of this increase was a result of higher federal taxes on crude oil. Average wellhead prices, subject to regulation since 1974, rose $20.77 per cubic metre to average $118.80 per cubic metre for the year.

Table 10 compares average costs of crude oil (excluding taxes) at Montreal with the estimated cost of crude oil at Chicago. The gap between Canadian domestic and imported prices increased to $144.47 per cubic metre from $132.03 in 1980. Thus, even though the volume of subsidized imports increased only 4.8 percent, total import compensation outlays rose 15.6 percent to $3.2 billion.

Total remaining established reserves of crude oil and equivalent hydrocarbons increased 11.0 million cubic metres to 1 154.1 million cubic metres. However, this includes estimates of frontier reserves which are not likely to contribute to Canada's oil supply until late in the 1980's. More important to the immediate oil needs of the country, there was a significant decline in conventional oil reserves in the western basin. This decline was concentrated in Alberta where reserves of crude oil and equivalent hydrocarbons dropped 63.1 million cubic metres to 792.9 million cubic metres. The National Energy Program was cited by industry as the reason for a severe downturn in drilling activity. The number of oil and gas well completions declined by 20.1 percent to 7 165 wells.

Consumption of natural gas declined 5.5 percent to 45.0 billion cubic metres. With exports to the United States also declining by 4.3 percent to 21.6 billion cubic metres, Canada's natural gas surplus continued to grow. Remaining established reserves at year end were 2 563 billion cubic metres, an increase of 73 billion cubic metres from 1980.

Production of marketable natural gas declined 3.7 percent to 67.5 billion cubic metres, of which 87.9 percent was produced in Alberta.

Electricity generation totalled 378 billion kilowatt hours, up 3.0 percent from 1980. Exports to the United States, which increased 17.2 percent to 35.4 billion kilowatt hours, accounted for 9.3 percent of total Canadian production.

Coal sales were up in both domestic and export markets because it has become an increasingly attractive fuel for the generation of electricity. Domestic production rose 9.3 percent in 1981 to 40.1 megatonnes. Canada became a net exporter of coal in 1981 as imports and exports totalled 14.8 and 15.7 megatonnes respectively.

TABLE 7

AVERAGE OLD OIL FIELD PRICE*

Year	Date of Price Change	$ per Barrel
1981	Oct. 1	21.25
1982	Jan. 1	23.50
1982	July 1	25.75
1983	Jan. 1	29.75
1983	July 1	33.75
1984	Jan. 1	37.75
1984	July 1	41.75
1985	Jan. 1	45.75
1985	July 1	49.75
1986	Jan. 1	53.75
1986	July 1	57.75

*Old oil prices shown are subject to a price limitation of 75 percent of international price.

TABLE 8

ALBERTA BORDER PRICE FOR NATURAL GAS

Year	Date of Price Change	$ per GJ
1981	Sept. 1	1.701 62
1982	Feb. 1	1.934 63
1982	Aug. 1	2.167 64
1983	Feb. 1	2.400 65
1983	Aug. 1	2.633 66
1984	Feb. 1	2.866 67
1984	Aug. 1	3.099 68
1985	Feb. 1	3.332 69
1985	Aug. 1	3.565 70
1986	Feb. 1	3.798 71
1986	Aug. 1	4.031 72

TABLE 9

CONSUMPTION OF PRIMARY ENERGY BY SOURCE

(percent)

	1981	1980
Oil	38.0	42.0
Natural Gas	18.0	18.0
Coal	10.0	9.0
Primary Electricity	29.0	27.0
Others	5.0	4.0

TABLE 10

CRUDE OIL PRICE COMPARISON(1)

(C. $ per cubic metre)

Year	Average Alberta Crude at Montreal	Imported Crude Delivered to Montreal	United States Cost of Crude at Chicago(2)
1977	69.92	95.03	79.73
1978	83.07	103.15	92.50
1979	89.93	148.14	133.54
1980	105.11	237.14	211.20
1981	127.93	272.42	272.63

(1) Excludes Taxes

(2) A.P.M.C. Estimate

FINANCIAL — PETROLEUM

statement "a"

ALBERTA PETROLEUM MARKETING COMMISSION

BALANCE SHEET

As At December 31, 1981

ASSETS

	1981	1980
OPERATING FUND		
Current:		
Cash (Note 3)	**$ 2,544,292**	$ 101,969
Short-term deposits	**—**	1,425,000
Accounts receivable	**510,073**	204,975
Prepaid expenses	**914**	—
	3,055,279	1,731,944
Fixed:		
Furniture and equipment, at cost	**771,331**	191,678
	3,826,610	1,923,622
PETROLEUM MARKETING FUND		
Cash (Note 3)	**9,837,814**	9,421,283
Accounts receivable (Note 4)	**578,727,072**	469,901,519
Inventory, at cost	**14,751,188**	14,189,525
	603,316,074	493,512,327
	$607,142,684	$495,435,949

The accompanying notes are part of these financial statements.

LIABILITIES

	1981	1980
OPERATING FUND		
Current:		
Accounts payable	**$ 549,744**	$ 112,249
Deferred revenue	**2,505,535**	1,619,695
	3,055,279	1,731,944
Capital surplus arising from furniture and equipment provided from income	**771,331**	191,678
	3,826,610	1,923,622
PETROLEUM MARKETING FUND		
Accounts payable to Crown lessees	**328,270,673**	267,051,269
Crown royalty payable	**236,282,479**	196,345,957
Buy/sell, freehold and transportation payable	**38,762,922**	30,115,101
	603,316,074	493,512,327
	$607,142,684	$495,435,949

statement "b"

ALBERTA PETROLEUM MARKETING COMMISSION

STATEMENT OF REVENUE AND EXPENDITURE
OPERATING FUND

For The Year Ended December 31, 1981

	1981	1980
Revenue:		
Contributions by the Province of Alberta	**$2,209,121**	$1,562,803
Interest earnings	**2,310,168**	1,047,044
	4,519,289	2,609,847
Expenditure:		
Salaries and wages	**2,037,259**	1,446,739
Furniture and equipment	**577,750**	51,383
Technical studies	**452,677**	114,521
Rental, premises	**343,751**	266,192
Leasehold improvements	**240,572**	117,422
Employee benefits	**187,317**	137,062
Travel and business meetings	**186,832**	127,769
Computer services	**134,667**	118,467
Consultants, personnel	**91,544**	47,602
Printing, stationery and office supplies	**87,274**	77,541
Postage and freight	**41,101**	19,916
Rental, office equipment and furnishings	**36,904**	23,806
Advertising	**32,808**	9,422
Library publications and periodicals	**27,091**	21,678
Telephone	**26,359**	17,503
Equipment maintenance	**4,315**	3,968
Insurance	**1,712**	1,327
Miscellaneous	**9,356**	7,529
	4,519,289	2,609,847
Excess of revenue over expenditure	**$ —**	$ —

statement "c"

ALBERTA PETROLEUM MARKETING COMMISSION

STATEMENT OF REVENUE AND EXPENDITURE
PETROLEUM MARKETING FUND

For The Year Ended December 31, 1981

	1981	1980
Revenue: (Note 5)		
Sales — Direct Marketing	**$5,565,440,064**	$3,805,629,401
Sales of petroleum delivered from Crown leases	**—**	1,248,882,160
	5,565,440,064	5,054,511,561
Expenditure:		
Purchases	**273,207,851**	142,658,712
Transportation	**95,013,988**	61,594,425
	368,221,839	204,253,137
Lessees' share	**3,134,982,788**	2,890,408,237
Royalty share	**2,062,235,437**	1,959,850,187
	5,565,440,064	5,054,511,561
Excess of revenue over expenditure	**$ —**	$ —

ALBERTA PETROLEUM MARKETING COMMISSION

NOTES TO THE FINANCIAL STATEMENTS

December 31, 1981

Note 1 Authority

The Alberta Petroleum Marketing Commission operates under the authority of The Petroleum Marketing Act, Chapter 96, Statutes of Alberta 1973, as amended.

Note 2 Significant Accounting Policies

General:

These financial statements have been prepared in accordance with generally accepted accounting principles except that no depreciation has been provided on fixed assets as purchases (including leasehold improvements) are charged to operations in the year of acquisition. Furniture and equipment is shown on the balance sheet at original cost with the offsetting credit to capital surplus.

Deferred Revenue:

The unexpended portion of contributions received from the Province of Alberta has been deferred to cover operating costs for the period to March 31, 1982. Contributions by the Province are based on a yearly budget for the period April 1 to March 31.

Operating Fund Expenditure:

The Natural Gas Pricing Agreement Act Fund and the Natural Gas Price Administration Act Fund are administered by the Alberta Petroleum Marketing Commission pursuant to their respective Acts. Accordingly, the expenditure related to the administration of these Funds is reflected in the Statement of Revenue and Expenditure — Operating Fund.

Inventory:

The inventory represents the Crown royalty share of petroleum deliveries from Crown lease properties remaining in the feeder pipelines at December 31.

Statement of Changes in Financial Position:

A statement of changes in financial position is not provided as disclosure in these financial statements is considered to be adequate.

Note 3 Cash

Arrangements with the Commission's bankers provide for interest at commercial rates on all account balances.

Note 4 Petroleum Marketing Fund Accounts Receivable

Petroleum Marketing Fund accounts receivable consist of the following:

	1981	1980
Transactions related to December petroleum deliveries	**$578,491,502**	$469,845,849
Prior months' adjustments, net	**235,570**	55,670
	$578,727,072	$469,901,519

Note 5 Implementation of the Direct Marketing System of Crown Petroleum

The activities of the Commission changed April 1, 1980, with the implementation of the Direct Marketing System. Pursuant to these activities, the Commission takes delivery of the petroleum from Crown leases at the battery or other facility and is responsible for the transportation to the point of sale and the sale thereof. 'Sales — Direct Marketing' represents these new activities.

'Sales of petroleum delivered from Crown leases' represents the sale of Crown lease petroleum for the first three months of 1980. These sales were made to Crude Oil Purchasers at the battery or other facility.

Note 6 Syncrude Project

The Alberta Petroleum Marketing Commission, through agency agreements with the Province of Alberta and PanCanadian Petroleum Limited, markets their share of leased substance from the Syncrude Project. The Commission, acting by appointment from the Province of Alberta, also markets the Crown royalty share of leased substance.

The marketing activities undertaken by the Commission relative to these transactions are not reflected in these financial statements.

Note 7 Lease Commitment

Effective December 1, 1981, the Commission signed a fifteen year lease for office accommodation. The minimum annual rental is $692,360.

Note 8 Approval of Financial Statements

These financial statements were approved by management on April 29, 1982.

ALBERTA LEGISLATURE

OFFICE OF THE AUDITOR GENERAL

AUDITOR'S REPORT

To the Members of the
Alberta Petroleum Marketing Commission

I have examined the balance sheet of the Alberta Petroleum Marketing Commission as at December 31, 1981 and the statements of revenue and expenditure for the Operating Fund and the Petroleum Marketing Fund for the year then ended. My examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as I considered necessary in the circumstances.

In my opinion, these financial statements present fairly the financial position of the Commission as at December 31, 1981 and the results of its operations for the year then ended in accordance with the disclosed basis of accounting described in Note 2 to the financial statements applied on a basis consistent with that of the preceding year.

C.A.
Auditor General

Edmonton, Alberta
April 29, 1982

FINANCIAL — NATURAL GAS

statement "a"

NATURAL GAS PRICING AGREEMENT ACT FUND
BALANCE SHEET
As At December 31, 1981

ASSETS

	1981	1980
Cash (Note 3)	**$ 21,924,996**	$ 12,786,019
Accounts receivable (Note 4)	**256,213,349**	128,725
	$278,138,345	$ 12,914,744

LIABILITIES

Price adjustments payable	**$274,315,468**	$ 12,914,744
Market development incentive payable (Note 5)	**$ 3,822,877**	$ —
	$278,138,345	$ 12,914,744

The accompanying notes are part
of these financial statements.

NATURAL GAS PRICING AGREEMENT ACT FUND
STATEMENT OF REVENUE AND EXPENDITURE
For The Two Months Ended December 31, 1981

Revenue:	
Natural gas sales	**$1,143,189,851**
Interest earnings	**604,651**
Transferred from Natural Gas Price Administration Act Fund	**15,619,085**
	1,159,413,587
Expenditure:	
Natural gas purchases	**678,290,867**
Price adjustments	**477,299,843**
Market development incentive (Note 5)	**3,822,877**
	1,159,413,587
Excess of revenue over expenditure	**$ —**

NATURAL GAS PRICING AGREEMENT ACT FUND
NOTES TO THE FINANCIAL STATEMENTS
December 31, 1981

Note 1 Authority

The Natural Gas Pricing Agreement Act Fund is operated under the authority of The Natural Gas Pricing Agreement Act, Chapter 38, Statutes of Alberta 1975, as amended. Under the terms of the Act, the Fund is held and administered by the Alberta Petroleum Marketing Commission. Upon commencement of a federal-Alberta agreement on gas pricing, a natural gas pricing order issued under The Natural Gas Pricing Agreement Act came into effect on November 1, 1981, and applies to natural gas transactions from that date. A transfer into the Fund of all of the money from the Natural Gas Price Administration Act Fund was made in December. Payments that would have been made from the Natural Gas Price Administration Act Fund will be made from the Natural Gas Pricing Agreement Act Fund.

Note 2 Significant Accounting Policies

Administration Costs:

In accordance with The Natural Gas Pricing Agreement Act, the Fund is administered by the Alberta Petroleum Marketing Commission. Costs of administration are not reflected in the financial statements of the Fund.

Statement of Changes in Financial Position:

A statement of changes in financial position is not provided as disclosure in these financial statements is considered to be adequate.

Note 3 Cash

Arrangements with the Commission's bankers provide for interest at commercial rates on all account balances.

Note 4 Accounts Receivable

Accounts receivable as at December 31, 1981 consist primarily of net proceeds from December natural gas sales. Accounts receivable as at December 31, 1980 consisted of interest receivable.

Note 5 Market Development Incentive Payments

Pursuant to the federal-Alberta agreement on gas pricing dated November 1, 1981, payments out of the Fund are required to be made by the Commission to the Government of Canada for the purpose of facilitating the expansion of markets in provinces east of Alberta for gas produced in Alberta.

Note 6 Comparative Figures

Comparative figures have not been presented in the statement of revenue and expenditure as the statement reflects natural gas sales and purchases and price adjustments for the two months ended December 31, 1981 only. Transactions prior to November 1, 1981 are reflected in the financial statements of the Natural Gas Price Administration Act Fund.

Note 7 Approval of Financial Statements

These financial statements were approved by management on April 29, 1982.

ALBERTA LEGISLATURE

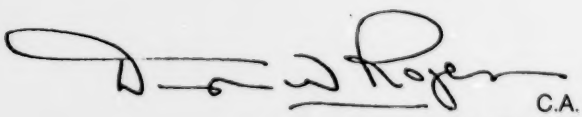
OFFICE OF THE AUDITOR GENERAL

AUDITOR'S REPORT

To the Members of the
Alberta Petroleum Marketing Commission

I have examined the balance sheet of the Natural Gas Pricing Agreement Act Fund as at December 31, 1981 and the statement of revenue and expenditure for the two months then ended. My examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as I considered necessary in the circumstances.

In my opinion, these financial statements present fairly the financial position of the Fund as at December 31, 1981 and the results of its operations for the two months then ended in accordance with generally accepted accounting principles applied on a basis consistent with that of the preceding year.



C.A.
Auditor General

Edmonton, Alberta
April 29, 1982

statement "a"

NATURAL GAS PRICE ADMINISTRATION ACT FUND
BALANCE SHEET
As At December 31, 1981

ASSETS

	1981	1980
Cash (Note 3)	—	$ 8,734,416
Accounts receivable (Note 4)	—	$222,846,528
	—	$231,580,944

LIABILITIES

Price adjustments payable	—	$231,580,944
	—	$231,580,944

The accompanying notes are part of these financial statements.

statement "b"

NATURAL GAS PRICE ADMINISTRATION ACT FUND
STATEMENT OF REVENUE AND EXPENDITURE
For The Year Ended December 31, 1981

Revenue:	
Natural gas sales	**$4,510,074,966**
Interest earnings	**3,312,375**
	4,513,387,341
Expenditure:	
Natural gas purchases	**2,800,405,576**
Price adjustments	**1,697,362,680**
	4,497,768,256
Transfer to Natural Gas Pricing Agreement Act Fund	**15,619,085**
	4,513,387,341
Excess of revenue over expenditure	**$ —**

NATURAL GAS PRICE ADMINISTRATION ACT FUND
NOTES TO THE FINANCIAL STATEMENTS
December 31, 1981

Note 1 Authority

The Natural Gas Price Administration Act Fund is operated under the authority of The Natural Gas Price Administration Act, Chapter 70, Statutes of Alberta 1975, as amended. Under the terms of the Act, the Fund is held and administered by the Alberta Petroleum Marketing Commission. The Act ceased to apply to natural gas transactions after October 31, 1981 pursuant to a federal-Alberta agreement on gas pricing under The Natural Gas Pricing Agreement Act. All of the money in the Fund was transferred to the Natural Gas Pricing Agreement Act Fund in December for transaction of all subsequent payments that would have been made from the Natural Gas Price Administration Act Fund.

Note 2 Significant Accounting Policies

Administration Costs:

In accordance with The Natural Gas Price Administration Act, the Fund is administered by the Alberta Petroleum Marketing Commission. Costs of administration are not reflected in the financial statements of the Fund.

Statement of Changes in Financial Position:

A statement of changes in financial position is not provided as disclosure in these financial statements is considered to be adequate.

Note 3 Cash

Arrangements with the Commission's bankers provide for interest at commercial rates on all account balances.

Note 4 Accounts Receivable

Accounts receivable as at December 31, 1980 consisted primarily of net proceeds from December natural gas sales.

Note 5 Comparative Figures

Comparative figures have not been presented in the statement of revenue and expenditure as the statement reflects natural gas sales and purchases and price adjustments for the ten months ended October 31, 1981 only. Transactions subsequent to October 31, 1981 are reflected in the financial statements of the Natural Gas Pricing Agreement Act Fund.

Note 6 Approval of Financial Statements

These financial statements were approved by management on April 29, 1982.

ALBERTA LEGISLATURE

OFFICE OF THE AUDITOR GENERAL

AUDITOR'S REPORT

To the Members of the
Alberta Petroleum Marketing Commission

I have examined the balance sheet of the Natural Gas Price Administration Act Fund as at December 31, 1981 and the statement of revenue and expenditure for the year then ended. My examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as I considered necessary in the circumstances.

In my opinion, these financial statements present fairly the financial position of the Fund as at December 31, 1981 and the results of its operations for the year then ended in accordance with generally accepted accounting principles applied on a basis consistent with that of the preceding period.

C.A.
Auditor General

Edmonton, Alberta
April 29, 1982

COMMISSION PERSONNEL

COMMISSION MEMBERS

Chairman ..... D. W. Minion
Vice-Chairman ..... R. H. Purdy
Member ..... R. D. Hall

ADMINISTRATION AND FINANCE

Executive Director ..... D. MacLachlan
Director, Accounting ..... T. N. R. Fons
Director, Computer Services ..... R. W. Tovell
Director, Office Services ..... B. A. Lilly

ENGINEERING AND PLANNING

Executive Director ..... R. S. Dunwald
Director, Technical Evaluations ..... G. E. Baerg

NATURAL GAS

Executive Director ..... V. M. Thomas
Director, Cost of Service ..... W. A. McKain
Director, Natural Gas Sales and Claims ..... A. Smith

PETROLEUM

Executive Director ..... J. E. MacKenzie
Director, Petroleum Marketing ..... R. J. McLean
Director, Petroleum Operations ..... R. J. Smith
Director, Petroleum Supply ..... D. M. Olineck

COMMISSION AUDITOR ..... E. K. Adams

SECRETARY AND SOLICITOR ..... D. C. Hetland

STAFF AND OFFICES

At December 31, 1981 the staff of the Commission numbered 68.
The Commission head office is in Calgary and it maintains an office in Edmonton.